equipment, natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters.

(d) For onshore natural gas processing, report CO_2 and CH_4 emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Blowdown vent stacks.

(4) Dehydrator vents.

(5) Acid gas removal vents.

(6) Flare stack emissions.

(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(e) For onshore natural gas transmission compression, report CO_2 and CH_4 emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Transmission storage tanks.

(4) Blowdown vent stacks.

(5) Natural gas pneumatic device venting.

(6) [Reserved]

(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(f) For underground natural gas storage, report CO_2 and CH_4 emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Natural gas pneumatic device venting.

(4) [Reserved]

(5) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(g) For LNG storage, report CO_2 and CH_4 emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Equipment leaks from valves; pump seals; connectors; vapor recovery compressors, and other equipment leak sources.

(h) LNG import and export equipment, report CO_2 and CH_4 emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Blowdown vent stacks.

(4) Equipment leaks from valves, pump seals, connectors, vapor recovery compressors, and other equipment leak sources.

(i) For natural gas distribution, report emissions from the following sources:

(1) Above ground meters and regulators at custody transfer city gate stations, including equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines. Customer meters are excluded.

(2) Above ground meters and regulators at non-custody transfer city gate stations, including station equipment leaks. Customer meters are excluded.

(3) Below ground meters and regulators and vault equipment leaks. Customer meters are excluded.

(4) Pipeline main equipment leaks.

(5) Service line equipment leaks.

(6) Report under subpart W of this part the emissions of CO_2, CH_4, and N_2O emissions from stationary fuel combustion sources following the methods in § 98.233(z).

(j) All applicable industry segments must report the CO_2, CH_4, and N_2O emissions from each flare.

(k) Report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary fuel combustion unit by following the requirements of subpart C. Onshore petroleum and natural gas production facilities must report stationary and portable combustion emissions as specified in paragraph (c) of this section. Natural gas distribution facilities must report stationary combustion emissions as specified in paragraph (i) of this section.

(l) You must report under subpart PP of this part (Suppliers of Carbon Dioxide), CO_2 emissions captured and transferred off site by following the requirements of subpart PP.

§ 98.233 Calculating GHG emissions.

You must calculate and report the annual GHG emissions as prescribed in this section. For actual conditions, reporters must use average atmospheric conditions or typical operating conditions as applicable to the respective monitoring methods in this section.

(a) *Natural gas pneumatic device venting.* Calculate CH_4 and CO_2 emissions from continuous high bleed, continuous low bleed, and intermittent bleed natural gas pneumatic devices using Equation W–1 of this section.

$$Mass_{s,i} = Count * EF * GHG_i * Conv_i * 24 * 365 \qquad \text{(Eq. W-1)}$$

Where:

$Mass_{s,i}$ = Annual total mass GHG emissions in metric tons CO_2e per year at standard conditions from a natural gas pneumatic device vent, for GHG i.

Count = Total number of continuous high bleed, continuous low bleed, or intermittent bleed natural gas pneumatic devices of each type as determined in paragraph (a)(1) of this section.

EF = Population emission factors for natural gas pneumatic device venting listed in Tables W–1A, W–3, and W–4 of this subpart for onshore petroleum and natural gas production, onshore natural gas transmission compression, and underground natural gas storage facilities, respectively.

GHG_i = For onshore petroleum and natural gas production facilities, concentration of GHG i, CH_4 or CO_2, in produced natural gas; for facilities listed in § 98.230(a)(3) through (a)(8), GHG_i equals 1.

$Conv_i$ = Conversion from standard cubic feet to metric tons CO_2e; 0.000410 for CH_4, and 0.00005357 for CO_2.

24 * 365 = Conversion to yearly emissions estimate.

(1) For onshore petroleum and natural gas production, provide the total number of continuous high bleed, continuous low bleed, or intermittent bleed natural gas pneumatic devices of each type as follows:

(i) In the first calendar year, for the total number of each type, you may count the total of each type, or count any percentage number of each type plus an engineering estimate based on best available data of the number not counted.

(ii) In the second consecutive year, for the total number of each type, you may count the total of each type, or count any percentage number of each type plus an engineering estimate based on best available data of the number not counted.

(iii) In the third consecutive calendar year, complete the count of all pneumatic devices, including any changes to equipment counted in prior years.

(iv) For the calendar year immediately following the third consecutive calendar year, and for calendar years thereafter, facilities must update the total count of pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.

(2) For onshore natural gas transmission compression and underground natural gas storage, all natural gas pneumatic devices must be counted in the first year and updated every calendar year.

(b) [Reserved]

(c) *Natural gas driven pneumatic pump venting.* Calculate CH_4 and CO_2 emissions from natural gas driven pneumatic pump venting using Equation W–2 of this section. Natural gas driven pneumatic pumps covered in paragraph (e) of this section do not have to report emissions under paragraph (c) of this section.

$$Mass_{s,i} = Count * EF * GHG_i * Conv_i * 24 * 365 \qquad \text{(Eq. W-2)}$$

Where:

$Mass_{s,i}$ = Annual total mass GHG emissions in metric tons CO_2e per year at standard conditions from all natural gas pneumatic pump venting, for GHG i.

Count = Total number of natural gas pneumatic pumps.

EF = Population emission factors for natural gas pneumatic pump venting listed in Tables W–1A of this subpart for onshore petroleum and natural gas production.

GHG_i = Concentration of GHG i, CH_4 or CO_2, in produced natural gas.

$Conv_i$ = Conversion from standard cubic feet to metric tons CO_2e; 0.000410 for CH_4, and 0.00005357 for CO_2.

24 * 365 = Conversion to yearly emissions estimate.

(d) *Acid gas removal (AGR) vents.* For AGR vent (including processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), calculate emissions for CO_2 only (not CH_4) vented directly to the atmosphere or through a flare, engine (*e.g.* permeate from a membrane or de-adsorbed gas from a pressure swing adsorber used as fuel supplement), or sulfur recovery plant using any of the calculation methodologies described in paragraph (d) of this section.

(1) *Calculation Methodology 1.* If you operate and maintain a CEMS that measures CO_2 emissions according to subpart C of this part, you must calculate CO_2 emissions under this subpart by following the Tier 4 Calculation Methodology and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). If CEMS and/or volumetric flow rate monitor are not available, you may install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion).

(2) *Calculation Methodology 2.* If CEMS is not available, use the CO_2 composition and annual volume of vent gas to calculate emissions using Equation W–3 of this section.

$$E_{a,CO2} = V_S * Vol_{CO2} \qquad \text{(Eq. W-3)}$$

Where:

$E_{a,CO2}$ = Annual volumetric CO_2 emissions at actual conditions, in cubic feet per year.

V_S = Total annual volume of vent gas flowing out of the AGR unit in cubic feet per year at actual conditions as determined by flow meter using methods set forth in §98.234(b).

Vol_{CO2} = Volume fraction of CO_2 content in vent gas out of the AGR unit as determined in (d)(6) of this section.

(3) *Calculation Methodology 3.* If using CEMS or vent meter is not an option, use the inlet or outlet gas flow rate of the acid gas removal unit to calculate emissions for CO_2 using Equation W–4 of this section.

$$E_{a,CO2} = \left(V + \alpha * \left(V * \left(Vol_I - Vol_O\right)\right)\right) * \left(Vol_I - Vol_O\right) \qquad \text{(Eq. W-4)}$$

Where:

$E_{a,CO2}$ = Annual volumetric CO_2 emissions at actual condition, in cubic feet per year.

V = Total annual volume of natural gas flow into or out of the AGR unit in cubic feet per year at actual condition as determined using methods specified in paragraph (d)(5) of this section.

α = Factor is 1 if the outlet stream flow is measured. Factor is 0 if the inlet stream flow is measured.

Vol_I = Volume fraction of CO_2 content in natural gas into the AGR unit as determined in paragraph (d)(7) of this section.

Vol_O = Volume fraction of CO_2 content in natural gas out of the AGR unit as determined in paragraph (d)(8) of this section.

(4) *Calculation Methodology 4.* Calculate emissions using any standard simulation software packages, such as AspenTech HYSYS® and API 4679 AMINECalc, that uses the Peng-Robinson equation of state, and speciates CO_2 emissions. A minimum of the following determined for typical operating conditions over the calendar year by engineering estimate and process knowledge based on best available data must be used to characterize emissions:

(i) Natural gas feed temperature, pressure, and flow rate.

(ii) Acid gas content of feed natural gas.

(iii) Acid gas content of outlet natural gas.

(iv) Unit operating hours, excluding downtime for maintenance or standby.

(v) Exit temperature of natural gas.

(vi) Solvent pressure, temperature, circulation rate, and weight.

(5) Record the gas flow rate of the inlet and outlet natural gas stream of an AGR unit using a meter according to methods set forth in § 98.234(b). If you do not have a continuous flow meter, either install a continuous flow meter or use an engineering calculation to determine the flow rate.

(6) If continuous gas analyzer is not available on the vent stack, either install a continuous gas analyzer or take quarterly gas samples from the vent gas stream to determine Vol_{CO2} according to methods set forth in § 98.234(b).

(7) If a continuous gas analyzer is installed on the inlet gas stream, then the continuous gas analyzer results must be used. If continuous gas analyzer is not available, either install a continuous gas analyzer or take quarterly gas samples from the inlet gas stream to determine Vol_I according to methods set forth in § 98.234(b).

(8) Determine volume fraction of CO_2 content in natural gas out of the AGR unit using one of the methods specified in paragraph (d)(8) of this section.

(i) If a continuous gas analyzer is installed on the outlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, you may install a continuous gas analyzer.

(ii) If a continuous gas analyzer is not available or installed, quarterly gas samples may be taken from the outlet gas stream to determine Vol_O according to methods set forth in § 98.234(b).

(iii) Use sales line quality specification for CO_2 in natural gas.

(9) Calculate CO_2 volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(10) Mass CO_2 emissions shall be calculated from volumetric CO_2 emissions using calculations in paragraph (v) of this section.

(11) Determine if emissions from the AGR unit are recovered and transferred outside the facility. Adjust the emission estimated in paragraphs (d)(1) through (d)(10) of this section downward by the magnitude of emission recovered and transferred outside the facility.

(e) *Dehydrator vents.* For dehydrator vents, calculate annual CH_4, CO_2 and N_2O (when flared) emissions using calculation methodologies described in paragraphs (e)(1) or (e)(2) of this section.

(1) *Calculation Methodology 1.* Calculate annual mass emissions from dehydrator vents with throughput greater than or equal to 0.4 million standard cubic feet per day using a software program, such as AspenTech HYSYS® or GRI–GLYCalc, that uses the Peng-Robinson equation of state to calculate the equilibrium coefficient, speciates CH_4 and CO_2 emissions from dehydrators, and has provisions to include regenerator control devices, a separator flash tank, stripping gas and a gas injection pump or gas assist pump. A minimum of the following parameters determined by engineering estimate based on best available data must be used to characterize emissions from dehydrators:

(i) Feed natural gas flow rate.

(ii) Feed natural gas water content.

(iii) Outlet natural gas water content.

(iv) Absorbent circulation pump type (natural gas pneumatic/air pneumatic/electric).

(v) Absorbent circulation rate.

(vi) Absorbent type: including triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG).

(vii) Use of stripping natural gas.

(viii) Use of flash tank separator (and disposition of recovered gas).

(ix) Hours operated.

(x) Wet natural gas temperature and pressure.

(xi) Wet natural gas composition. Determine this parameter by selecting one of the methods described under paragraph (e)(2)(xi) of this section.

(A) Use the wet natural gas composition as defined in paragraph (u)(2)(i) of this section.

(B) If wet natural gas composition cannot be determined using paragraph (u)(2)(i) of this section, select a representative analysis.

(C) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as specified in §98.234(b)(1) to sample and analyze wet natural gas composition.

(D) If only composition data for dry natural gas is available, assume the wet natural gas is saturated.

(2) *Calculation Methodology 2.* Calculate annual CH_4 and CO_2 emissions from glycol dehydrators with throughput less than 0.4 million cubic feet per day using Equation W–5 of this section:

$$E_{s,i} = EF_i * Count * 1000 \qquad \text{(Eq. W-5)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions (either CO_2 or CH_4) at standard conditions in cubic feet.

EF_i = Population emission factors for glycol dehydrators in thousand standard cubic feet per dehydrator per year. Use 74.5 for CH_4 and 3.26 for CO_2 at 68 °F and 14.7 psia or 73.4 for CH_4 and 3.21 for CO_2 at 60 °F and 14.7 psia.

Count = Total number of glycol dehydrators with throughput less than 0.4 million cubic feet.

1000 = Conversion of EF_i in thousand standard cubic to cubic feet.

(3) Determine if dehydrator unit has vapor recovery. Adjust the emissions estimated in paragraphs (e)(1) or (e)(2) of this section downward by the magnitude of emissions captured.

(4) Calculate annual emissions from dehydrator vents to flares or regenerator fire-box/fire tubes as follows:

(A) Use the dehydrator vent volume and gas composition as determined in paragraphs (e)(1) and (e)(2) of this section.

(B) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine dehydrator vent emissions from the flare or regenerator combustion gas vent.

(5) Dehydrators that use desiccant shall calculate emissions from the amount of gas vented from the vessel every time it is depressurized for the desiccant refilling process using Equation W–6 of this section. Desiccant dehydrators covered in (e)(5) of this section do not have to report emissions under (i) of this section.

$$E_{s,n} = \frac{(H * D^2 * P * P_2 * \%G * 365 days/yr)}{(4 * P_1 * T * 1,000 cf/Mcf * 100)} \qquad \text{(Eq. W-6)}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions in cubic feet.

H = Height of the dehydrator vessel (ft).

D = Inside diameter of the vessel (ft).

P_1 = Atmospheric pressure (psia).

P_2 = Pressure of the gas (psia).

P = pi (3.14).

%G = Percent of packed vessel volume that is gas.

T = Time between refilling (days).

100 = Conversion of %G to fraction.

(6) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(f) *Well venting for liquids unloadings.* Calculate CO_2 and CH_4 emissions from well venting for liquids unloading using one of the calculation methodologies described in paragraphs (f)(1), (f)(2) or (f)(3) of this section.

(1) *Calculation Methodology 1.* For one well of each unique well tubing diameter and producing horizon/formation combination in each gas producing field (see §98.238 for the definition of Field) where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing, a recording flow meter shall be installed on the vent line used to vent gas from the well (*e.g.*

on the vent line off the wellhead separator or atmospheric storage tank) according to methods set forth in § 98.234(b). Calculate emissions from well venting for liquids unloading using Equation W–7 of this section.

$$E_{a,n} = \sum_h \sum_t T_{h,t} * FR_{h,t} \qquad \text{(Eq. W-7)}$$

Where:

$E_{a,n}$ = Annual natural gas emissions at actual conditions in cubic feet.

$T_{h,t}$ = Cumulative amount of time in hours of venting from all wells of the same tubing diameter (t) and producing horizon (h)/formation combination during the year.

$FR_{h,t}$ = Average flow rate in cubic feet per hour of the measured well venting for the duration of the liquids unloading, under actual conditions as determined in paragraph (f)(1)(i) of this section.

(i) Determine the well vent average flow rate as specified under paragraph (f)(1)(i) of this section.

(A) The average flow rate per hour of venting is calculated for each unique tubing diameter and producing horizon/formation combination in each producing field by averaging the recorded flow rates for the recorded time of one representative well venting to the atmosphere.

(B) This average flow rate is applied to all wells in the field that have the same tubing diameter and producing horizon/formation combination, for the number of hours of venting these wells.

(C) A new average flow rate is calculated every other calendar year for each reporting field and horizon starting the first calendar year of data collection.

(ii) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(2) *Calculation Methodology 2.* Calculate emissions from each well venting for liquids unloading using Equation W–8 of this section.

$$E_{a,n} = \{(0.37\times10^{-3}) * CD^2 * WD * SP * N_V\} + \{SFR * (HR-1.0) * Z\} \qquad \text{(Eq. W-8)}$$

Where:

$E_{a,n}$ = Annual natural gas emissions at actual conditions, in cubic feet/year.

0.37×10^{-3} = {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).

CD = Casing diameter (inches).

WD = Well depth to first producing horizon (feet).

SP = Shut-in pressure (psia).

N_V = Number of vents per year.

SFR = Average sales flow rate of gas well in cubic feet per hour.

HR = Hours that the well was left open to the atmosphere during unloading.

1.0 = Hours for average well to blowdown casing volume at shut-in pressure.

Z = If HR is less than 1.0 then Z is equal to 0. If HR is greater than or equal to 1.0 then Z is equal to 1.

(i) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(ii) [Reserved]

(3) *Calculation Methodology 3.* Calculate emissions from each well venting to the atmosphere for liquids unloading with plunger lift assist using Equation W–9 of this section.

$$E_{a,n} = \{(0.37\times10^{-3}) * TD^2 * WD * SP * N_V\} + \{SFR * (HR-0.5) * Z\} \qquad \text{(Eq. W-9)}$$

Where:

$E_{a,n}$ = Annual natural gas emissions at actual conditions, in cubic feet/year.

0.37×10^{-3} = {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).

TD = Tubing diameter (inches).

WD = Tubing depth to plunger bumper (feet).

SP = Sales line pressure (psia).

N_V = Number of vents per year.

SFR = Average sales flow rate of gas well in cubic feet per hour.

HR = Hours that the well was left open to the atmosphere during unloading.

0.5 = Hours for average well to blowdown tubing volume at sales line pressure.

Z = If HR is less than 0.5 then Z is equal to 0. If HR is greater than or equal to 0.5 then Z is equal to 1.

(i) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(ii) [Reserved]

(4) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(g) *Gas well venting during completions and workovers from hydraulic fracturing.* Calculate CH_4, CO_2 and N_2O (when flared) annual emissions from gas well venting during completions involving hydraulic fracturing in wells and well workovers using Equation W–10 of this section. Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric total gas emissions using calculations in paragraphs (u) and (v) of this section.

$$E_{a,n} = (T * FR) - EnF - SG \qquad \text{(Eq. W-10)}$$

Where:

$E_{a,n}$ = Annual volumetric total gas emissions in cubic feet at standard conditions from gas well venting during completions following hydraulic fracturing.

T = Cumulative amount of time in hours of all well completion venting in a field during the year reporting.

FR = Average flow rate in cubic feet per hour, under actual conditions, converted to standard conditions, as required in paragraph (g)(1) of this section.

EnF = Volume of CO_2 or N_2 injected gas in cubic feet at standard conditions that was injected into the reservoir during an energized fracture job. If the fracture process did not inject gas into the reservoir, then EnF is 0. If injected gas is CO_2 then EnF is 0.

SG = Volume of natural gas in cubic feet at standard conditions that was recovered into a sales pipeline. If no gas was recovered for sales, SG is 0.

(1) The average flow rate for gas well venting to the atmosphere or to a flare during well completions and workovers from hydraulic fracturing shall be determined using either of the calculation methodologies described in this paragraph (g)(1) of this section.

(i) *Calculation Methodology 1.* For one well completion in each gas producing field and for one well workover in each gas producing field, a recording flow meter (digital or analog) shall be installed on the vent line, ahead of a flare if used, to measure the backflow venting event according to methods set forth in §98.234(b).

(A) The average flow rate in cubic feet per hour of venting to the atmosphere or routed to a flare is determined from the flow recording over the period of backflow venting.

(B) The respective flow rates are applied to all well completions in the producing field and to all well workovers in the producing field for the total number of hours of venting of each of these wells.

(C) New flow rates for completions and workovers are measured every other calendar year for each reporting gas producing field and gas producing geologic horizon in each gas producing field starting in the first calendar year of data collection.

(D) Calculate total volumetric flow rate at standard conditions using calculations in paragraph (t) of this section.

(ii) *Calculation Methodology 2.* For one well completion in each gas producing field and for one well workover in each gas producing field, record the well flowing pressure upstream (and downstream in subsonic flow) of a well choke according to methods set forth in §98.234(b) to calculate intermittent well flow rate of gas during venting to the atmosphere or a flare. Calculate emissions using Equation W–11 of this section for subsonic flow or Equation W–12 of this section for sonic flow:

$$FR = 1.27*10^5 * A * \sqrt{3430 * T_u * \left[\left(\frac{P_2}{P_1} \right)^{1.515} - \left(\frac{P_2}{P_1} \right)^{1.758} \right]} \quad \text{(Eq. W-11)}$$

Where:

FR = Average flow rate in cubic feet per hour, under subsonic flow conditions.

A = Cross sectional area of orifice (m^2).

P_1 = Upstream pressure (psia).

T_u = Upstream temperature (degrees Kelvin).

P_2 = Downstream pressure (psia).

3430 = Constant with units of $m^2/(sec^2 * K)$.

$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

$$FR = 1.27*10^5 * A * \sqrt{187.08 * T_u} \quad \text{(Eq. W-12)}$$

Where:

FR = Average flow rate in cubic feet per hour, under sonic flow conditions.

A = Cross sectional area of orifice (m^2).

T_u = Upstream temperature (degrees Kelvin).

187.08 = Constant with units of $m^2/(sec^2 * K)$.

$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

(A) The average flow rate in cubic feet per hour of venting across the choke is calculated for one well completion in each gas producing field and for one well workover in each gas producing field by averaging the gas flow rates during venting to the atmosphere or routing to a flare.

(B) The respective flow rates are applied to all well completions in the gas producing field and to all well workovers in the gas producing field for the total number of hours of venting of each of these wells.

(C) Flow rates for completions and workovers in each field shall be calculated once every two years for each reporting gas producing field and geologic horizon in each gas producing field starting in the first calendar year of data collection.

(D) Calculate total volumetric flow rate at standard conditions using calculations in paragraph (t) of this section.

(2) The volume of CO_2 or N_2 injected into the well reservoir during energized hydraulic fractures will be measured using an appropriate meter as described in 98.234(b) or using receipts of gas purchases that are used for the energized fracture job.

(i) Calculate gas volume at standard conditions using calculations in paragraph (t) of this section.

(ii) [Reserved]

(3) The volume of recovered completion gas sent to a sales line will be measured using existing company records. If data does not exist on sales gas, then an appropriate meter as described in 98.234(b) may be used.

(i) Calculate gas volume at standard conditions using calculations in paragraph (t) of this section.

(ii) [Reserved]

(4) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric total emissions using calculations in paragraphs (u) and (v) of this section.

(5) Determine if the well completion or workover from hydraulic fracturing recovered gas with purpose designed equipment that separates saleable gas from the backflow, and sent this gas to a sales line (*e.g.* reduced emissions completion).

(i) Use the factor SG in Equation W–10 of this section, to adjust the emissions estimated in paragraphs (g)(1) through (g)(4) of this section by the magnitude of emissions captured using reduced emission completions as determined by engineering estimate based on best available data.

(ii) [Reserved]

(6) Calculate annual emissions from gas well venting during well completions and workovers from hydraulic fracturing to flares as follows:

(i) Use the total gas well venting volume during well completions and workovers as determined in paragraph (g) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine gas well venting during well completions and workovers using hydraulic fracturing emissions from the flare. This adjustment to emissions from completions using flaring versus completions without flaring accounts for the conversion of CH_4 to CO_2 in the flare.

(h) *Gas well venting during completions and workovers without hydraulic fracturing.* Calculate CH_4, CO_2 and N_2O (when flared) emissions from each gas well venting during well completions and workovers not involving hydraulic fracturing and well workovers not involving hydraulic fracturing using Equation W–13 of this section:

$$E_{a,n} = N_{wo} * EF_{wo} + \sum_{f} V_f * T_f \qquad \text{(Eq. W-13)}$$

Where:

$E_{a,n}$ = Annual natural gas emissions in cubic feet at actual conditions from gas well venting during well completions and workovers without hydraulic fracturing.

N_{wo} = Number of workovers per field not involving hydraulic fracturing in the reporting year.

EF_{wo} = Emission Factor for non-hydraulic fracture well workover venting in actual cubic feet per workover. EF_{wo} = 2,454 standard cubic feet per well workover without hydraulic fracturing.

f = Total number of well completions without hydraulic fracturing in a field.

V_f = Average daily gas production rate in cubic feet per hour of each well completion without hydraulic fracturing. This is the total annual gas production volume divided by total number of hours the wells produced to the sales line. For completed wells that have not established a production rate, you may use the average flow rate from the first 30 days of production. In the event that the well is completed less than 30 days from the end of the calendar year, the first 30 days of the production straddling the current and following calendar years shall be used.

T_f = Time each well completion without hydraulic fracturing was venting in hours during the year.

(1) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(2) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(3) Calculate annual emissions from gas well venting during well completions and workovers not involving hydraulic fracturing to flares as follows:

(i) Use the gas well venting volume during well completions and workovers as determined in paragraph (h) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine gas well venting during well completions and workovers emissions without hydraulic fracturing from the flare.

(i) *Blowdown vent stacks.* Calculate CO_2 and CH_4 blowdown vent stack emissions from depressurizing equipment to the atmosphere (excluding depressurizing to a flare, over-pressure relief, operating pressure control venting and blowdown of non-GHG gases; desiccant dehydrator blowdown venting before reloading is covered in paragraph (e)(5) of this section) as follows:

(1) Calculate the total volume (including pipelines, compressor case or cylinders, manifolds, suction bottles, discharge bottles, and vessels) between isolation valves determined by engineering estimate based on best available data.

(2) If the total volume between isolation valves is greater than or equal to 50 standard cubic feet, retain logs of the number of blowdowns for each

equipment type (including but not limited to compressors, vessels, pipelines, headers, fractionators, and tanks). Blowdown volumes smaller than 50 standard cubic feet are exempt from reporting under paragraph (i) of this section.

(3) Calculate the total annual venting emissions for each equipment type using Equation W–14 of this section:

$$E_{s,n} = N * \left(V_v \left(\frac{(459.67 + T_s) P_a}{(459.67 + T_a) P_s} \right) - V_v * C \right) \qquad \text{(Eq. W-14)}$$

Where:

$E_{s,n}$ = Annual natural gas venting emissions at standard conditions from blowdowns in cubic feet.

N = Number of repetitive blowdowns for each equipment type of a unique volume in calendar year.

V_v = Total volume of blowdown equipment chambers (including pipelines, compressors and vessels) between isolation valves in cubic feet.

C = Purge factor that is 1 if the equipment is not purged or zero if the equipment is purged using non-GHG gases.

T_s = Temperature at standard conditions (°F).

T_a = Temperature at actual conditions in the blowdown equipment chamber (°F).

P_s = Absolute pressure at standard conditions (psia).

P_a = Absolute pressure at actual conditions in the blowdown equipment chamber (psia).

(4) Calculate both CH_4 and CO_2 mass emissions from volumetric natural gas emissions using calculations in paragraph (v) of this section.

(5) Calculate total annual venting emissions for all blowdown vent stacks by adding all standard volumetric and mass emissions determined in Equation W–14 and paragraph (i)(4) of this section.

(j) *Onshore production storage tanks.* Calculate CH_4, CO_2 and N_2O (when flared) emissions from atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids from onshore petroleum and natural gas production facilities (including stationary liquid storage not owned or operated by the reporter), calculate annual CH_4 and CO_2 emissions using any of the calculation methodologies described in this paragraph (j).

(1) *Calculation Methodology 1.* For separators with oil throughput greater than or equal to 10 barrels per day. Calculate annual CH_4 and CO_2 emissions from onshore production storage tanks using operating conditions in the last wellhead gas-liquid separator before liquid transfer to storage tanks. Calculate flashing emissions with a software program, such as AspenTech HYSYS® or API 4697 E&P Tank, that uses the Peng-Robinson equation of state, models flashing emissions, and speciates CH_4 and CO_2 emissions that will result when the oil from the separator enters an atmospheric pressure storage tank. A minimum of the following parameters determined for typical operating conditions over the year by engineering estimate and process knowledge based on best available data must be used to characterize emissions from liquid transferred to tanks.

(i) Separator temperature.

(ii) Separator pressure.

(iii) Sales oil or stabilized oil API gravity.

(iv) Sales oil or stabilized oil production rate.

(v) Ambient air temperature.

(vi) Ambient air pressure.

(vii) Separator oil composition and Reid vapor pressure. If this data is not available, determine these parameters by selecting one of the methods described under paragraph (j)(1)(viii) of this section.

(A) If separator oil composition and Reid vapor pressure default data are provided with the software program, select the default values that most closely match your separator pressure first, and API gravity secondarily.

(B) If separator oil composition and Reid vapor pressure data are available through your previous analysis, select the latest available analysis that is representative of produced crude oil or condensate from the field.

(C) Analyze a representative sample of separator oil in each field for oil composition and Reid vapor pressure using an appropriate standard method published by a consensus-based standards organization.

(2) *Calculation Methodology 2.* Calculate annual CH_4 and CO_2 emissions from onshore production storage tanks for wellhead gas-liquid separators with oil throughput greater than or equal to 10 barrels per day by assuming that all of the CH_4 and CO_2 in solution at separator temperature and pressure is emitted from oil sent to storage tanks. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as described in §98.234(b)(1) to sample and analyze separator oil composition at separator pressure and temperature.

(3) *Calculation Methodology 3.* For wells with oil production greater than or equal to 10 barrels per day that flow directly to atmospheric storage tanks without passing through a wellhead separator, calculate CH_4 and CO_2 emissions by either of the methods in paragraph (j)(3) of this section:

(i) If well production oil and gas compositions are available through your previous analysis, select the latest available analysis that is representative of produced oil and gas from the field and assume all of the CH_4 and CO_2 in both oil and gas are emitted from the tank.

(ii) If well production oil and gas compositions are not available, use default oil and gas compositions in software programs, such as API 4697 E&P Tank, that most closely match your well production gas/oil ratio and API gravity and assume all of the CH_4 and CO_2 in both oil and gas are emitted from the tank.

(4) *Calculation Methodology 4.* For wells with oil production greater than or equal to 10 barrels per day that flow to a separator not at the well pad, calculate CH_4 and CO_2 emissions by either of the methods in paragraph (j)(4) of this section:

(i) If well production oil and gas compositions are available through your previous analysis, select the latest available analysis that is representative of oil at separator pressure determined by best available data and assume all of the CH_4 and CO_2 in the oil is emitted from the tank.

(ii) If well production oil composition is not available, use default oil composition in software programs, such as API 4697 E&P Tank, that most closely match your well production API gravity and pressure in the off-well pad separator determined by best available data. Assume all of the CH_4 and CO_2 in the oil phase is emitted from the tank.

(5) *Calculation Methodology 5.* For well pad gas-liquid separators and for wells flowing off a well pad without passing through a gas-liquid separator with throughput less than 10 barrels per day use Equation W–15 of this section:

$$E_{s,i} = EF_i * Count \quad \text{(Eq. W-15)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions (either CO_2 or CH_4) at standard conditions in cubic feet.

EF_i = Populations emission factor for separators and wells in thousand standard cubic feet per separator or well per year, for crude oil use 4.3 for CH_4 and 2.9 for CO_2 at 68 °F and 14.7 psia, and for gas condensate use 17.8 for CH_4 and 2.9 for CO_2 at 68 °F and 14.7 psia.

Count = Total number of separators and wells with throughput less than 10 barrels per day.

(6) Determine if the storage tank receiving your separator oil has a vapor recovery system.

(i) Adjust the emissions estimated in paragraphs (j)(1) through (j)(5) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

(ii) [Reserved]

(7) Determine if the storage tank receiving your separator oil is sent to flare(s).

(i) Use your separator flash gas volume and gas composition as determined in this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine your contribution to storage tank emissions from the flare.

(8) Calculate emissions from occurrences of well pad gas-liquid separator liquid dump valves not closing during the calendar year by using Equation W–16 of this section.

$$E_{s,i} = \left(CF_n * E_n * T_n\right) + \left(E_t * \left(8760 - T_n\right)\right) \qquad \text{(Eq. W-16)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each storage tank in cubic feet.

E_n = Storage tank emissions as determined in Calculation Methodologies 1, 2, or 5 in paragraphs (j)(1) through (j)(5) of this section (with wellhead separators) during time T_n in cubic feet per hour.

T_n = Total time the dump valve is not closing properly in the calendar year in hours. T_n is estimated by maintenance or operations records (records) such that when a record shows the valve to be open improperly, it is assumed the valve was open for the entire time period preceding the record starting at either the beginning of the calendar year or the previous record showing it closed properly within the calendar year. If a subsequent record shows it is closing properly, then assume from that time forward the valve closed properly until either the next record of it not closing properly or, if there is no subsequent record, the end of the calendar year.

CF_n = Correction factor for tank emissions for time period T_n is 3.87 for crude oil production. Correction factor for tank emissions for time period T_n is 5.37 for gas condensate production. Correction factor for tank emissions for time period T_n is 1.0 for periods when the dump valve is closed.

E_t = Storage tank emissions as determined in Calculation Methodologies 1, 2, or 3 in paragraphs (j)(1) through (j)(5) of this section at maintenance or operations during the time the dump valve is closing properly (ie. 8760–T_n) in cubic feet per hour.

(9) Calculate both CH_4 and CO_2 mass emissions from volumetric natural gas emissions using calculations in paragraph (v) of this section.

(k) *Transmission storage tanks.* For condensate storage tanks, either water or hydrocarbon, without vapor recovery or thermal control devices in onshore natural gas transmission compression facilities calculate CH_4, CO_2 and N_2O (when flared) annual emissions from compressor scrubber dump valve leakage as follows:

(1) Monitor the tank vapor vent stack annually for emissions using an optical gas imaging instrument according to methods set forth in § 98.234(a)(1) for a duration of 5 minutes. Or you may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods set forth in § 98.234(a)(5).

(2) If the tank vapors are continuous for 5 minutes, or the acoustic leak detection device detects a leak, then use one of the following two methods in paragraph (k)(2) of this section to quantify emissions:

(i) Use a meter, such as a turbine meter, to estimate tank vapor volumes according to methods set forth in § 98.234(b). If you do not have a continuous flow measurement device, you may install a flow measuring device on the tank vapor vent stack.

(ii) Use an acoustic leak detection device on each scrubber dump valve connected to the tank according to the method set forth in § 98.234(a)(5).

(iii) Use the appropriate gas composition in paragraph (u)(2)(iii) of this section.

(3) If the leaking dump valve(s) is fixed following leak detection, the annual emissions shall be calculated from the beginning of the calendar year to the time the valve(s) is repaired.

(4) Calculate emissions from storage tanks to flares as follows:

(i) Use the storage tank emissions volume and gas composition as determined in either paragraph (j)(1)of this section or with an acoustic leak detection device in paragraphs (k)(1) through (k)(3) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine storage tank emissions from the flare.

(l) *Well testing venting and flaring*. Calculate CH_4, CO_2 and N_2O (when flared) well testing venting and flaring emissions as follows:

(1) Determine the gas to oil ratio (GOR) of the hydrocarbon production from each well tested.

(2) If GOR cannot be determined from your available data, then you must measure quantities reported in this section according to one of the two procedures in paragraph (l)(2) of this section to determine GOR:

(i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(ii) Or you may use an industry standard practice as described in § 98.234(b).

(3) Estimate venting emissions using Equation W–17 of this section.

$$E_{a,n} = GOR * FR * D \quad \text{(Eq. W-17)}$$

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions from well testing in cubic feet under actual conditions.

GOR = Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

FR = Flow rate in barrels of oil per day for the well being tested.

D = Number of days during the year, the well is tested.

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(5) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(6) Calculate emissions from well testing to flares as follows:

(i) Use the well testing emissions volume and gas composition as determined in paragraphs (l)(1) through (3) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine well testing emissions from the flare.

(m) *Associated gas venting and flaring*. Calculate CH_4, CO_2 and N_2O (when flared) associated gas venting and flaring emissions not in conjunction with well testing (refer to paragraph (l): Well testing venting and flaring of this section) as follows:

(1) Determine the GOR of the hydrocarbon production from each well whose associated natural gas is vented or flared. If GOR from each well is not available, the GOR from a cluster of wells in the same field shall be used.

(2) If GOR cannot be determined from your available data, then use one of the two procedures in paragraph (m)(2) of this section to determine GOR:

(i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(ii) Or you may use an industry standard practice as described in § 98.234(b).

(3) Estimate venting emissions using Equation W–18 of this section.

$$E_{a,n} = GOR * V \quad \text{(Eq. W-18)}$$

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions from associated gas venting under actual conditions, in cubic feet.

GOR = Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

V = Volume of oil produced in barrels in the calendar year during which associated gas was vented or flared.

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(5) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(6) Calculate emissions from associated natural gas to flares as follows:

(i) Use the associated natural gas volume and gas composition as determined in paragraph (m)(1) through (4) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine associated gas emissions from the flare.

(n) *Flare stack emissions.* Calculate CO_2, CH_4, and N_2O emissions from a flare stack as follows:

(1) If you have a continuous flow measurement device on the flare, you must use the measured flow volumes to calculate the flare gas emissions. If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If you do not have a continuous flow measurement device on the flare, you can install a flow measuring device on the flare or use engineering calculations based on process knowledge, company records, and best available data.

(2) If you have a continuous gas composition analyzer on gas to the flare, you must use these compositions in calculating emissions. If you do not have a continuous gas composition analyzer on gas to the flare, you must use the appropriate gas compositions for each stream of hydrocarbons going to the flare as follows:

(i) For onshore natural gas production, determine natural gas composition using (u)(2)(i) of this section.

(ii) For onshore natural gas processing, when the stream going to flare is natural gas, use the GHG mole percent in feed natural gas for all streams upstream of the de-methanizer or dew point control, and GHG mole percent in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities.

(iii) When the stream going to the flare is a hydrocarbon product stream, such as ethane, propane, butane, pentane-plus and mixed light hydrocarbons, then use a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data.

(3) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 98 percent.

(4) Calculate GHG volumetric emissions at actual conditions using Equations W–19, W–20, and W–21 of this section.

$$E_{a,CH4}(un-combusted) = V_a * (1-\eta) * X_{CH4} \quad \text{(Eq. W-19)}$$

$$E_{a,CO2}(un-combusted) = V_a * X_{CO2} \quad \text{(Eq. W-20)}$$

$$E_{a,CO2}(combusted) = \sum_j \eta * V_a * Y_j * R_j \quad \text{(Eq. W-21)}$$

Where:

E_{a,CH_4}(un-combusted) = Contribution of annual un-combusted CH_4 emissions from flare stack in cubic feet, under actual conditions.

E_{a,CO_2}(un-combusted) = Contribution of annual un-combusted CO_2 emissions from flare stack in cubic feet, under actual conditions.

E_{a,CO_2}(combusted) = Contribution of annual combusted CO_2 emissions from flare stack in cubic feet, under actual conditions.

V_a = Volume of gas sent to flare in cubic feet, during the year.

η = Fraction of gas combusted by a burning flare (default is 0.98). For gas sent to an unlit flare, η is zero.

X_{CH_4} = Mole fraction of CH_4 in gas to the flare.

X_{CO_2} = Mole fraction of CO_2 in gas to the flare.

Y_j = Mole fraction of gas hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes-plus).

R_j = Number of carbon atoms in the gas hydrocarbon constituent j: 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes-plus).

(5) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(6) Calculate both CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (v) of this section.

(7) Calculate total annual emission from flare stacks by summing Equation W–40, Equation W–19, Equation W–20 and Equation W–21 of this section.

(8) Calculate N_2O emissions from flare stacks using Equation W–40 in paragraph (z) of this section.

(9) The flare emissions determined under paragraph (n) of this section must be corrected for flare emissions calculated and reported under other paragraphs of this section to avoid double counting of these emissions.

(o) *Centrifugal compressor venting.* Calculate CH_4, CO_2 and N_2O (when flared) emissions from both wet seal and dry seal centrifugal compressor vents as follows:

(1) For each centrifugal compressor covered by § 98.232 (d)(2), (e)(2), (f)(2), (g)(2), and (h)(2) you must conduct an annual measurement in the operating mode in which it is found. Measure emissions from all vents (including emissions manifolded to common vents) including wet seal oil degassing vents, unit isolation valve vents, and blowdown valve vents. Record emissions from the following vent types in the specified compressor modes during the annual measurement.

(i) Operating mode, blowdown valve leakage through the blowdown vent, wet seal and dry seal compressors.

(ii) Operating mode, wet seal oil degassing vents.

(iii) Not operating, depressurized mode, unit isolation valve leakage through open blowdown vent, without blind flanges, wet seal and dry seal compressors.

(A) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode.

(2) For wet seal oil degassing vents, determine vapor volumes sent to an atmospheric vent or flare, using a temporary meter such as a vane anemometer or permanent flow meter according to 98.234(b) of this section. If you do not have a permanent flow meter, you may install a permanent flow meter on the wet seal oil degassing tank vent.

(3) For blowdown valve leakage and unit isolation valve leakage to open ended vents, you can use one of the following methods: Calibrated bagging or high volume sampler according to methods set forth in § 98.234(c) and § 98.234(d), respectively. For through valve leakage, such as isolation valves, you may use an acoustic leak detection device according to methods set forth in § 98.234(a). If you do not have a flow meter, you may install a port for insertion of a temporary meter, or a permanent flow meter, on the vents.

(4) Estimate annual emissions using the flow measurement and Equation W–22 of this section.

$$E_{s,i,m} = MT_m * T_m * M_{i,m} * (1 - B_m) \qquad \text{(Eq. W-22)}$$

Where:

$E_{s,i,m}$ = Annual GHG_i (either CH_4 or CO_2) volumetric emissions at standard conditions, in cubic feet.

MT_m = Measured gas emissions in standard cubic feet per hour.

T_m = Total time the compressor is in the mode for which $E_{s,i}$ is being calculated, in the calendar year in hours.

$M_{i,m}$ = Mole fraction of GHG_i in the vent gas; use the appropriate gas compositions in paragraph (u)(2) of this section.

B_m = Fraction of operating time that the vent gas is sent to vapor recovery or fuel gas as determined by keeping logs of the number of operating hours for the vapor recovery system and the time that vent gas is directed to the fuel gas system or sales.

(5) Calculate annual emissions from each centrifugal compressor using Equation W–23 of this section.

$$E_{s,i} = \sum_m EF_m * T_m * GHG_i \qquad \text{(Eq. W-23)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each centrifugal compressor in cubic feet.

EF_m = Reporter emission factor for each mode m, in cubic feet per hour, from Equation W–24 of this section as calculated in paragraph 6.

T_m = Total time in hours per year the compressor was in each mode, as listed in paragraph (o)(1)(i) through (o)(1)(iii).

GHG_i = For onshore natural gas processing facilities, concentration of GHG $_i$, CH_4 or CO_2, in produced natural gas or feed natural gas; for other facilities listed in § 98.230(a)(4) through (a)(8),GHG_i equals 1.

(6) You shall use the flow measurements of operating mode wet seal oil degassing vent, operating mode blowdown valve vent and not operating depressurized mode isolation valve vent for all the reporter's compressor modes not measured in the calendar year to develop the following emission factors using Equation W–24 of this section for each emission source and mode as listed in paragraph (o)(1)(i) through (o)(1)(iii).

$$EF_m = \sum \frac{MT_m}{Count_m} \qquad \text{(Eq. W-24)}$$

Where:

EF_m = Reporter emission factors for compressor in the three modes m (as listed in paragraph (o)(1)(i) through (o)(1)(iii)) in cubic feet per hour.

MT_m = Flow Measurements from all centrifugal compressor vents in each mode in (o)(1)(i) through (o)(1)(iii) of this section in cubic feet per hour.

$Count_m$ = Total number of compressors measured.

m = Compressor mode as listed in paragraph (o)(1)(i) through (o)(1)(iii).

(i) The emission factors must be calculated annually. You must use all measurements from the current calendar year and the preceding two calendar years, totaling three consecutive calendar years of measurements in paragraph (o)(6) of this section.

(ii) [Reserved]

(7) Onshore petroleum and natural gas production shall calculate emissions from centrifugal compressor wet seal oil degassing vents as follows:

$$E_{s,i} = Count * EF_i \quad \text{(Eq. W-25)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from centrifugal compressor wet seals in cubic feet.

Count = Total number of centrifugal compressors for the reporter.

EF_i = Emission factor for GHG $_i$. Use 12.2 million standard cubic feet per year per compressor for CH_4 and 538 thousand standard cubic feet per year per compressor for CO_2 at 68 °F and 14.7 psia or 12 million standard cubic feet per year per compressor for CH_4 and 530 thousand standard cubic feet per year per compressor for CO_2 at 60 °F and 14.7 psia.

(8) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(9) Calculate emissions from seal oil degassing vent vapors to flares as follows:

(i) Use the seal oil degassing vent vapor volume and gas composition as determined in paragraphs (o)(5) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine degassing vent vapor emissions from the flare.

(p) *Reciprocating compressor venting.* Calculate CH_4 and CO_2 emissions from all reciprocating compressor vents as follows. For each reciprocating compressor covered in §98.232(d)(1), (e)(1), (f)(1), (g)(1), and (h)(1) you must conduct an annual measurement for each compressor in the mode in which it is found during the annual measurement, except as specified in paragraph (p)(9) of this section. Measure emissions from (including emissions manifolded to common vents) reciprocating rod packing vents, unit isolation valve vents, and blowdown valve vents. Record emissions from the following vent types in the specified compressor modes during the annual measurement as follows:

(1) Operating or standby pressurized mode, blowdown vent leakage through the blowdown vent stack.

(2) Operating mode, reciprocating rod packing emissions.

(3) Not operating, depressurized mode, unit isolation valve leakage through the blowdown vent stack, without blind flanges.

(i) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years if this mode is not found in the annual measurement. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode.

(ii) [Reserved]

(4) If reciprocating rod packing and blowdown vent are connected to an open-ended vent line use one of the following two methods to calculate emissions:

(i) Measure emissions from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown vents using either calibrated bagging or high volume sampler according to methods set forth in §98.234(c) and §98.234(d), respectively.

(ii) Use a temporary meter such as a vane anemometer or a permanent meter such as an orifice meter to measure emissions from all vents (including emissions manifolded to a common vent) including rod packing vents and unit isolation valve leakage through blowdown vents according to methods set forth in §98.234(b). If you do not have a permanent flow meter, you may install a port for insertion of a temporary meter or a permanent flow meter on the vents. For through-valve leakage to open ended vents, such as unit isolation valves on not operating, depressurized compressors and blowdown valves on pressurized compressors, you may use an acoustic detection device according to methods set forth in §98.234(a).

(5) If reciprocating rod packing is not equipped with a vent line use the following method to calculate emissions:

(i) You must use the methods described in § 98.234(a) to conduct annual leak detection of equipment leaks from the packing case into an open distance piece, or from the compressor crank case breather cap or other vent with a closed distance piece.

(ii) Measure emissions found in paragraph (p)(5)(i) of this section using an appropriate meter, or calibrated bag, or high volume sampler according to methods set forth in § 98.234(b), (c), and (d), respectively.

(6) Estimate annual emissions using the flow measurement and Equation W–26 of this section.

$$E_{s,i,m} = MT_m * T_m * M_{i,m} \quad \text{(Eq. W-26)}$$

Where:

$E_{s,i,m}$ = Annual GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions, in cubic feet.

MT_m = Measured gas emissions in standard cubic feet per hour.

T_m = Total time the compressor is in the mode for which $E_{s,i,m}$ is being calculated, in the calendar year in hours.

$M_{i,m}$ = Mole fraction of GHG i in gas; use the appropriate gas compositions in paragraph (u)(2) of this section.

(7) Calculate annual emissions from each reciprocating compressor using Equation W–27 of this section.

$$E_{s,i} = \sum_m EF_m * T_m * GHG_i \quad \text{(Eq. W-27)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each reciprocating compressor in cubic feet.

EF_m = Reporter emission factor for each mode, m, in cubic feet per hour, from Equation W–28 of this section as calculated in paragraph (p)(7)(i) of this section.

T_m = Total time in hours per year the compressor was in each mode, m, as listed in paragraph (p)(1) through (p)(3).

GHG_i = For onshore natural gas processing facilities, concentration of GHG i, CH_4 or CO_2, in produced natural gas or feed natural gas; for other facilities listed in § 98.230(a)(4) through (a)(8), GHG_i equals 1.

m = Compressor mode as listed in paragraph (p)(1) through (p)(3).

(i) You shall use the flow meter readings from measurements of operating and standby pressurized blowdown vent, operating mode vents, not operating depressurized isolation valve vent for all the reporter's compressor modes not measured in the calendar year to develop the following emission factors using Equation W–28 of this section for each mode as listed in paragraph (p)(1) through (p)(3).

$$EF_m = \sum \frac{MT_m}{Count_m} \quad \text{(Eq. W-28)}$$

Where:

EF_m = Reporter emission factors for compressor in the three modes, m, in cubic feet per hour.

MT_m = Meter readings from all reciprocating compressor vents in each and mode, m, in cubic feet per hour.

$Count_m$ = Total number of compressors measured in each mode, m.

m = Compressor mode as listed in paragraph (p)(1) through (p)(3).

(A) You must combine emissions for blowdown vents, measured in the operating and standby pressurized modes.

(B) The emission factors must be calculated annually. You must use all measurements from the current calendar year and the preceding two calendar years, totaling three consecutive calendar years of measurements.

(ii) [Reserved]

(8) Determine if the reciprocating compressor vent vapors are sent to a vapor recovery system.

(i) Adjust the emissions estimated in paragraphs (p)(7) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

(ii) [Reserved]

(9) Onshore petroleum and natural gas production shall calculate emissions from reciprocating compressors as follows:

$$E_{s,i} = Count * EF_i \quad \text{(Eq. W-29)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from reciprocating compressors in cubic feet.

Count = Total number of reciprocating compressors for the reporter.

EF_i = Emission factor for GHG i. Use 9.63 thousand standard cubic feet per year per compressor for CH_4 and 0.535 thousand standard cubic feet per year per compressor for CO_2 at 68 °F and 14.7 psia or 9.48 thousand standard cubic feet per year per compressor for CH_4 and 0.527 thousand standard cubic feet per year per compressor for CO_2 at 60 °F and 14.7 psia.

(10) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (u) and (v) of this section.

(q) *Leak detection and leaker emission factors*. You must use the methods described in §98.234(a) to conduct leak detection(s) of equipment leaks from all sources listed in §98.232(d)(7), (e)(7), (f)(5), (g)(3), (h)(4), and (i)(1). This paragraph (q) applies to emissions sources in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of this paragraph (q) and do not need to be reported. If equipment leaks are detected for sources listed in this paragraph (q), calculate emissions using Equation W–30 of this section for each source with equipment leaks.

$$E_{s,i} = GHG_i * \sum_x EF_s * T_x \quad \text{(Eq. W-30)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each equipment leak source in cubic feet.

x = Total number of this type of emissions source found to be leaking during T_x.

EF_s = Leaker emission factor for specific sources listed in Table W–2 through Table W–7 of this subpart.

GHG_i = For onshore natural gas processing facilities, concentration of GHG_i, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; for other facilities listed in §98.230(a)(4) through (a)(8), GHG_i equals 1 for CH_4 and 1.1×10^{-2} for CO_2.

T_X = The total time the component was found leaking and operational, in hours. If one leak detection survey is conducted, assume the component was leaking for the entire calendar year. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the previous survey or the beginning of the calendar year. For the last leak detection survey in the calendar year, assume that all leaking components continue to leak until the end of the calendar year.

(1) You must select to conduct either one leak detection survey in a calendar year or multiple complete leak detection surveys in a calendar year. The number of leak detection surveys selected must be conducted during the calendar year.

(2) Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions using calculations in paragraph (v) of this section.

(3) Onshore natural gas processing facilities shall use the appropriate default leaker emission factors listed in Table W–2 of this subpart for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(4) Onshore natural gas transmission compression facilities shall use the appropriate default leaker emission factors listed in Table W–3 of this subpart for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(5) Underground natural gas storage facilities for storage stations shall use the appropriate default leaker emission factors listed in Table W–4 of this subpart for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(6) LNG storage facilities shall use the appropriate default leaker emission factors listed in Table W–5 of this subpart for equipment leaks detected from valves, pump seals, connectors, and other.

(7) LNG import and export facilities shall use the appropriate default leaker emission factors listed in Table W–6 of this subpart for equipment leaks detected from valves, pump seals, connectors, and other.

(8) Natural gas distribution facilities for above ground meters and regulators at city gate stations at custody transfer, shall use the appropriate default leaker emission factors listed in Table W–7 of this subpart for equipment leak detected from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines.

(r) *Population count and emission factors.* This paragraph applies to emissions sources listed in § 98.232 (c)(21), (f)(5), (g)(3), (h)(4), (i)(2), (i)(3), (i)(4) and (i)(5), on streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Tubing systems equal or less than one half inch diameter are exempt from the requirements of paragraph (r) of this section and do not need to be reported. Calculate emissions from all sources listed in this paragraph using Equation W–31 of this section.

$$E_{s,i} = Count_s * EF_s * GHG_i * T_s \qquad \text{(Eq. W-31)}$$

Where:

$E_{s,i}$ = Annual volumetric GHG emissions at standard conditions from each equipment leak source in cubic feet.

$Count_s$ = Total number of this type of emission source at the facility. Average component counts are provided by major equipment piece in Tables W–1B and Table W–1C of this subpart. Use average component counts as appropriate for operations in Eastern and Western U.S., according to Table W–1D of this subpart.

EF_s = Population emission factor for the specific source, s listed in Table W–1A and Tables W–3 through Table W–7 of this subpart. Use appropriate population emission factor for operations in Eastern and Western U.S., according to Table W–1D of this subpart. EF for non-custody transfer city gate stations is determined in Equation W–32.

GHG_i = For onshore petroleum and natural gas production facilities and onshore natural gas processing facilities, concentration of GHG i, CH_4 or CO_2, in produced natural gas or feed natural gas; for other facilities listed in § 98.230(a)(4) through (a)(8), GHG_i equals 1 for CH_4 and 1.1×10^{-2} for CO_2.

T_s = Total time the specific source s associated with the equipment leak emission was operational in the calendar year, in hours.

(1) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(2) Onshore petroleum and natural gas production facilities shall use the appropriate default population emission factors listed in Table W–1A of this subpart for equipment leaks from valves, connectors, open ended lines, pressure relief valves, pump, flanges, and other. Major equipment and components associated with gas wells are considered gas service components in reference to Table 1–A of this subpart and major natural gas equipment in reference to Table W–1B of this subpart. Major equipment and components associated with crude oil wells are considered crude service components in reference to Table 1–A of this subpart and major crude oil equipment in reference to Table W–1C of this subpart. Where facilities conduct EOR operations the emissions factor listed in Table W–1A of this subpart shall be used to estimate all streams of gases, including recycle CO_2 stream. The component count can be determined using either of the methodologies described in this paragraph (r)(2). The same methodology must be used for the entire calendar year.

(i) *Component Count Methodology 1.* For all onshore petroleum and natural gas production operations in the facility perform the following activities:

(A) Count all major equipment listed in Table W–1B and Table W–1C of this subpart.

(B) Multiply major equipment counts by the average component counts listed in Table W–1B and W–1C of this subpart for onshore natural gas production and onshore oil production, respectively. Use the appropriate factor in Table W–1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table W–1D of this subpart.

(ii) *Component Count Methodology 2.* Count each component individually for the facility. Use the appropriate factor in Table W–1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table W–1D of this subpart.

(3) Underground natural gas storage facilities for storage wellheads shall use the appropriate default population emission factors listed in Table W–4 of this subpart for equipment leak from connectors, valves, pressure relief valves, and open ended lines.

(4) LNG storage facilities shall use the appropriate default population emission factors listed in Table W–5 of this subpart for equipment leak from vapor recovery compressors.

(5) LNG import and export facilities shall use the appropriate default population emission factor listed in Table W–6 of this subpart for equipment leak from vapor recovery compressors.

(6) Natural gas distribution facilities shall use the appropriate emission factors as described in paragraph (r)(6) of this section.

(i) Below grade meters and regulators; mains; and services, shall use the appropriate default population emission factors listed in Table W–7 of this subpart.

(ii) Above grade meters and regulators at city gate stations not at custody transfer as listed in §98.232(i)(2), shall use the total volumetric GHG emissions at standard conditions for all equipment leak sources calculated in paragraph (q)(8) of this section to develop facility emission factors using Equation W–32 of this section. The calculated facility emission factor from Equation W–32 of this section shall be used in Equation W–31 of this section.

$$EF = \sum \frac{E_{s,i}}{Count} \quad \text{(Eq. W-32)}$$

Where:

EF = Facility emission factor for a meter at above grade M&R at city gate stations not at custody transfer in cubic feet per meter per year.

$E_{s,i}$ = Annual volumetric GHG emissions at standard condition from all equipment leak sources at all above grade M&R city gate stations at custody transfer, from paragraph (q) of this section.

Count = Total number of meter runs at all above grade M&R city gate stations at custody transfer.

(s) *Offshore petroleum and natural gas production facilities*. Report CO_2, CH_4, and N_2O emissions for offshore petroleum and natural gas production from all equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304.

(1) Offshore production facilities under BOEMRE jurisdiction shall report the same annual emissions as calculated and reported by BOEMRE in data collection and emissions estimation study published by BOEMRE referenced in 30 CFR 250.302 through 304 (GOADS).

(i) For any calendar year that does not overlap with the most recent BOEMRE emissions study publication year, report the most recent BOEMRE reported emissions data published by BOEMRE referenced in 30 CFR 250.302 through 304 (GOADS). Adjust emissions based on the operating time for the facility relative to the operating time in the most recent BOEMRE published study.

(ii) [Reserved]

(2) Offshore production facilities that are not under BOEMRE jurisdiction shall use monitoring methods and calculation methodologies published by BOEMRE referenced in 30 CFR 250.302 through 304 to calculate and report emissions (GOADS).

(i) For any calendar year that does not overlap with the most recent BOEMRE emissions study publication, report the most recent reported emissions data with emissions adjusted based on the operating time for the facility relative to operating time in the previous reporting period.

(ii) [Reserved]

(3) If BOEMRE discontinues or delays their data collection effort by more than 4 years, then offshore reporters shall once in every 4 years use the most recent BOEMRE data collection and emissions estimation methods to report emission from the facility sources.

(4) For either first or subsequent year reporting, offshore facilities either within or outside of BOEMRE jurisdiction that were not covered in the previous BOEMRE data collection cycle shall use the most recent BOEMRE data collection and emissions estimation methods published by BOEMRE referenced in 30 CFR 250.302 through 304 to calculate and report emissions (GOADS) to report emissions.

(t) *Volumetric emissions*. Calculate volumetric emissions at standard conditions as specified in paragraphs (t)(1) or (2) of this section determined by engineering estimate based on best available data unless otherwise specified.

(1) Calculate natural gas volumetric emissions at standard conditions by converting actual temperature and pressure of natural gas emissions to standard temperature and pressure of natural gas using Equation W–33 of this section.

$$E_{s,n} = \frac{E_{a,n} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s} \qquad \text{(Eq. W-33)}$$

Where:

$E_{s,n}$ = Natural gas volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet.

$E_{a,n}$ = Natural gas volumetric emissions at actual conditions in cubic feet.

T_s = Temperature at standard conditions (°F).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (psia).

P_a = Absolute pressure at actual conditions (psia).

(2) Calculate GHG volumetric emissions at standard conditions by converting actual temperature and pressure of GHG emissions to standard temperature and pressure using Equation W–34 of this section.

$$E_{s,i} = \frac{E_{a,i} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s} \quad \text{(Eq. W-34)}$$

Where:

$E_{s,i}$ = GHG i volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet.

$E_{a,i}$ = GHG i volumetric emissions at actual conditions in cubic feet.

T_s = Temperature at standard conditions (°F).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (psia).

P_a = Absolute pressure at actual conditions (psia).

(u) *GHG volumetric emissions.* Calculate GHG volumetric emissions at standard conditions as specified in paragraphs (u)(1) and (2) of this section determined by engineering estimate based on best available data unless otherwise specified.

(1) Estimate CH_4 and CO_2 emissions from natural gas emissions using Equation W–35 of this section.

$$E_{s,i} = E_{s,n} * M_i \quad \text{(Eq. W-35)}$$

Where:

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions in cubic feet.

$E_{s,n}$ = Natural gas volumetric emissions at standard conditions in cubic feet.

M_i = Mole fraction of GHG i in the natural gas.

(2) For Equation W–35 of this section, the mole fraction, M_i, shall be the annual average mole fraction for each facility, as specified in paragraphs (u)(2)(i) through (vii) of this section.

(i) GHG mole fraction in produced natural gas for onshore petroleum and natural gas production facilities. If you have a continuous gas composition analyzer for produced natural gas, you must use these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then you must use your most recent gas composition based on available sample analysis of the field.

(ii) GHG mole fraction in feed natural gas for all emissions sources upstream of the de-methanizer or dew point control and GHG mole fraction in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. If you have a continuous gas composition analyzer on feed natural gas, you must use these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in §98.234(b).

(iii) GHG mole fraction in transmission pipeline natural gas that passes through the facility for onshore natural gas transmission compression facilities.

(iv) GHG mole fraction in natural gas stored in underground natural gas storage facilities.

(v) GHG mole fraction in natural gas stored in LNG storage facilities.

(vi) GHG mole fraction in natural gas stored in LNG import and export facilities.

(vii) GHG mole fraction in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities.

(v) *GHG mass emissions.* Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions by converting the GHG volumetric emissions into mass emissions using Equation W–36 of this section.

$$Mass_{s,i} = E_{s,i} * \rho_i * GWP * 10^{-3} \quad \text{(Eq. W-36)}$$

Where:

$Mass_{s,i}$ = GHG i (either CH_4 or CO_2) mass emissions at standard conditions in metric tons CO_2e.

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions, in cubic feet.

ρ_i = Density of GHG i. Use 0.0538 kg/ft^3 for CO_2 and N_2O, and 0.0196 kg/ft^3 for CH_4 at 68 °F and 14.7 psia or 0.0530 kg/ft^3 for CO_2 and N_2O, and 0.0193 kg/ft^3 for CH_4 at 60 °F and 14.7 psia.

GWP = Global warming potential, 1 for CO_2, 21 for CH_4, and 310 for N_2O.

(w) *EOR injection pump blowdown.* Calculate CO_2 pump blowdown emissions as follows:

(1) Calculate the total volume in cubic feet (including pipelines, manifolds and vessels) between isolation valves.

(2) Retain logs of the number of blowdowns per calendar year.

(3) Calculate the total annual venting emissions using Equation W–37 of this section:

$$Mass_{c,i} = N * V_v * R_c * GHG_i * 10^{-3} \quad \text{(Eq. W-37)}$$

Where:

$Mass_{c,i}$ = Annual EOR injection gas venting emissions in metric tons at critical conditions "c" from blowdowns.

N = Number of blowdowns for the equipment in the calendar year.

V_v = Total volume in cubic feet of blowdown equipment chambers (including pipelines, manifolds and vessels) between isolation valves.

R_c = Density of critical phase EOR injection gas in kg/ft^3. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice to determine density of super critical EOR injection gas.

GHG_i = Mass fraction of GHG_i in critical phase injection gas.

1×10^{-3} = Conversion factor from kilograms to metric tons.

(x) EOR hydrocarbon liquids dissolved CO_2. Calculate dissolved CO_2 in hydrocarbon liquids produced through EOR operations as follows:

(1) Determine the amount of CO_2 retained in hydrocarbon liquids after flashing in tankage at STP conditions. Annual samples must be taken according to methods set forth in §98.234(b) to determine retention of CO_2 in hydrocarbon liquids immediately downstream of the storage tank. Use the annual analysis for the calendar year.

(2) Estimate emissions using Equation W–38 of this section.

$$Mass_{s,CO2} = S_{hl} * V_{hl} \quad \text{(Eq. W-38)}$$

Where:

$Mass_{s,CO2}$ = Annual CO_2 emissions from CO_2 retained in hydrocarbon liquids produced through EOR operations beyond tankage, in metric tons.

S_{hl} = Amount of CO_2 retained in hydrocarbon liquids in metric tons per barrel, under standard conditions.

V_{hl} = Total volume of hydrocarbon liquids produced at the EOR operations in barrels in the calendar year.

(y) [Reserved]

(z) *Onshore petroleum and natural gas production and natural gas distribution combustion emissions.* Calculate CO_2

CH_4 and N_2O combustion-related emissions from stationary or portable equipment as follows:

(1) If the fuel combusted in the stationary or portable equipment is listed in Table C–1 of subpart C of this part, or is a blend of fuels listed in Table C–1, use the Tier 1 methodology described in subpart C of this part (General Stationary Fuel Combustion Sources). If the fuel combusted is natural gas and is pipeline quality and has a minimum high heat value of 950 Btu per standard cubic foot, then the natural gas emission factor and high heat values listed in Tables C–1 and C–2 of this part may be used.

(2) For fuel combustion units that combust field gas or process vent gas, or any blend of field gas or process vent gas and fuels listed in Table C–1 of subpart C of this part, calculate combustion emissions as follows:

(i) If you have a continuous flow meter on the combustion unit, you must use the measured flow volumes to calculate the total flow of gas to the unit. If you do not have a permanent flow meter on the combustion unit, you may install a permanent flow meter on the combustion unit, or use company records or engineering calculations based on best available data on heat duty or horsepower to estimate volumetric unit gas flow.

(ii) If you have a continuous gas composition analyzer on fuel to the combustion unit, you must use these compositions for determining the concentration of gas hydrocarbon constituent in the flow of gas to the unit. If you do not have a continuous gas composition analyzer on gas to the combustion unit, you must use the appropriate gas compositions for each stream of hydrocarbons going to the combustion unit as specified in paragraph (u)(2)(i) of this section.

(iii) Calculate GHG volumetric emissions at actual conditions using Equations W–39 of this section.

$$E_{a,CO2} = \sum_{j} V_a * Y_j * R_j \qquad \text{(Eq. W-39)}$$

Where:

E_{a,CO_2} = Contribution of annual emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.

V_a = Volume of gas sent to combustion unit in cubic feet, during the year.

Y_j = Concentration of gas hydrocarbon constituents *j* (such as methane, ethane, propane, butane, and pentanes plus).

R_j = Number of carbon atoms in the gas hydrocarbon constituent *j;* 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus).

(3) External fuel combustion sources with a rated heat capacity equal to or less than 5 mmBtu/hr do not need to report combustion emissions. You must report the type and number of each external fuel combustion unit.

(4) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(5) Calculate both combustion-related CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (v) of this section.

(6) Calculate N_2O mass emissions using Equation W–40 of this section.

$$N_2O = \left(1\times10^{3}\right)\times Fuel\times HHV\times EF \qquad \text{(Eq. W-40)}$$

Where:

N_2O = Annual N_2O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Mass or volume of the fuel combusted (mass or volume per year, choose appropriately to be consistent with the units of HHV).

HHV = High heat value of the fuel from paragraphs (z)(8)(i), (z)(8)(ii) or (z)(8)(iii) of this section (units must be consistent with Fuel).

EF = Use 1.0×10^{-4} kg N_2O/mmBtu.

1×10^{-3} = Conversion factor from kilograms to metric tons.

(i) For fuels listed in Table C–1 of subpart C of this part, use the provided default HHV in the table.

(ii) For field gas or process vent gas, use 1.235×10^{-3} mmBtu/scf for HHV.

(iii) For fuels not listed in Table C–1 of subpart C of this part and not field gas or process vent gas, you must use the methodology set forth in the Tier 2 methodology described in subpart C of this part to determine HHV.

§ 98.234 Monitoring and QA/QC requirements.

The GHG emissions data for petroleum and natural gas emissions sources must be quality assured as applicable as specified in this section. Offshore petroleum and natural gas production facilities shall adhere to the monitoring and QA/QC requirements as set forth in 30 CFR 250.

(a) You must use any of the methods described as follows in this paragraph to conduct leak detection(s) of equipment leaks and through-valve leakage from all source types listed in § 98.233(k), (o), (p) and (q) that occur during a calendar year, except as provided in paragraph (a)(4) of this section.

(1) *Optical gas imaging instrument.* Use an optical gas imaging instrument for equipment leak detection in accordance with 40 CFR part 60, subpart A, § 60.18(i)(1) and (2) of the *Alternative work practice for monitoring equipment leaks.* Any emissions detected by the optical gas imaging instrument is a leak unless screened with Method 21 (40 CFR part 60, appendix A–7) monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, you must operate the optical gas imaging instrument to image the source types required by this subpart in accordance with the instrument manufacturer's operating parameters.

(2) *Method 21.* Use the equipment leak detection methods in 40 CFR part 60, appendix A–7, Method 21. If using Method 21 monitoring, if an instrument reading of 10,000 ppm or greater is measured, a leak is detected. Inaccessible emissions sources, as defined in 40 CFR part 60, are not exempt from this subpart. Owners or operators must use alternative leak detection devices as described in paragraph(a)(1) of this section to monitor inaccessible equipment leaks or vented emissions.

(3) *Infrared laser beam illuminated instrument.* Use an infrared laser beam illuminated instrument for equipment leak detection. Any emissions detected by the infrared laser beam illuminated instrument is a leak unless screened with Method 21 monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, you must operate the infrared laser beam illuminated instrument to detect the source types required by this subpart in accordance with the instrument manufacturer's operating parameters.

(4) *Optical gas imaging instrument.* An optical gas imaging instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(5) *Acoustic leak detection device.* Use the acoustic leak detection device to detect through-valve leakage. When using the acoustic leak detection device to quantify the through-valve leakage, you must use the instrument manufacturer's calculation methods to quantify the through-valve leak. When using the acoustic leak detection device, if a leak of 3.1 scf per hour or greater is calculated, a leak is detected. In addition, you must operate the acoustic leak detection device to monitor the source valves required by this subpart in accordance with the instrument manufacturer's operating parameters.

(b) You must operate and calibrate all flow meters, composition analyzers and pressure gauges used to measure quantities reported in § 98.233 according to the procedures in § 98.3(i) and the procedures in paragraph (b) of this section. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice. Consensus-based standards organizations